Grid West Risk-Reward Group
Problem Identification and Quantification Survey
Preliminary Results Posting

The Problem Identification and Quantification Survey (preliminary results) reflects responses submitted by 26 survey respondents. For each question, all of the responses are briefly summarized, however, responses that were "Not Applicable" are not referenced. For each question, the responses are clumped together, so that those comments that generally fall into the category of "perceived problems" and those that "do not perceive problems", are displayed together and separated by two rows. Given the commitment to "mask" the responses, the response comments reflect the "category" of respondent rather than the specific survey respondent itself, e.g., MTU: Major Transmitting Utility; GEN: Generator; MKTR: Marketer; TP: Transmission Provider; and, TDU; Transmission Dependent Utility.

				Problem Identification and Quantification Survey - preliminary results [draft_031105]
			588	Response Count
	1.			**Production Cost**
	1.	a.		Impact of Pancaked Rates
MTU	1.	a.	1	Inefficient dispatch happens often.
MTU	1.	a.	2	An extra wheel can be charged for a transformer.
GEN	1.	a.	3	Renewable resources are location dependent and therefore, pancaked rates have a signficant impact on these resources and make some projects too costly as a result.
MKTR	1.	a.	4	Pancaked transmission rates (and ancillary service charges) compounds the inefficiencies already caused by fixed-cost pricing of transmission services.
MKTR	1.	a.	5	Discounting polices could be used to create efficiencies absent in a fixed-cost pricing environment, however, this could require common reservation, scheduling and pricing systems.
MKTR	1.	a.	6	The impact of rate pancaking could be measured by comparing the price spread among market points including transmission, AS and losses costs with prices w/o transmission and AS costs.
MKTR	1.	a.	7	Selling to CA involves 2 BPA wheels; selling to Nevada involves 3 BPA wheels and 1 Pac wheel; transactions using the BPA system and another generally becomes uneconomic.
TP	1.	a.	8	Rate pancaking tends to limit the scope of the market. Respondent has surplus energy to sell, so any off-system sales tend to benefit their firm wholesale customers.
GEN	1.	a.	9	Not uncommon for respondent to purchase two separate transmission contracts for single transaction within a single transmission provider's control area.
GEN	1.	a.	10	Pricing of network and intertie capacity is separate and results in a pancaked rate to deliver power to California. Request, scheduling and tagging results in additional administrative burdens.
GEN	1.	a.	11	Rate pancakes do not result in production cost inefficiencies for customers that purchase power from PBL; sales are made at market hubs or the TBL border. Exceptions include La Grande, RATS, Rathdrum.
TDU	1.	a.	12	Pancakes can give "serving" utilities a price advantage over the market. More importantly, there isn't enough ATC to serve loads.
MTU	1.	a.	13	Parties scheduling transmission across the system face charges not limited to only the variable cost of the transaction, but also a fixed cost component. This fixed cost recovery, when assessed in real-time, inappropriately impedes the efficiency of the wholesale power market, especially when multiple transmission providers are involved.
MTU	1.	a.	14	Respondent believes it is inefficient for transmission users to have to pay for pricing pancakes that include both fixed and variable costs on a volumetric basis; and that a more efficient approach would be to have one fee to access the combined transmission grid, and then a variable or incremental cost for any congestion.
MTU	1.	a.	15	A wind project desiring to acquire integration service may find the product cost-prohibitive because the project may have to pay wheeling charges to deliver energy to the system providing the service, and additional wheeling charges to transport a shaped product to end users.
MTU	1.	a.	16	With respect to real-time dispatch of existing generation resources, some inefficiency may exist due to rate pancaking of hourly transmission service. Rate discounting or postage-stamp pricing cited as possible remedies.
GEN	1.	a.	17	It involves 3 wheels (2 BPA and another) to move power from the PNW to the Desert SW. In addition, ancillary services (scheduling and dispatch and reactive) are then charged 3 times.
MTU	1.	a.	18	Respondent has no current examples of rate pancakes that result in substantive production cost inefficiencies. Cites scope of BPA as the primary reason for this.
MTU	1.	a.	19	"Pancaking" of multiple long-term firm transmission rates may be an appropriate means of incorporating the cost of energy transportation in the evaluation of developing remote energy resources.
TDU	1.	a.	20	We are not affected by rate pancaking - we are a transmission dependent utility that doesn't operate a CA.
TDU	1.	a.	21	Normally, pancaked rates are invisible and 99% of our sales and purchases are within the borders of the host Control Area.
TDU	1.	a.	22	No issues associated with pancaking.
MTU	1.	a.	23	No examples of how/why rate pancakes result in production cost efficiencies.
MTU	1.	a.	24	Most of our transactions only involve the BPA Network and so pancaking hasn't be a significant issue.
TDU	1.	a.	25	Basis trading (through displacement) is used to get around some of these problems, but this depends on circumstances of willing buyers and sellers and risk (e.g. multiple unit contingencies).

				Problem Identification and Quantification Survey - preliminary results [draft_031105]
	1.	b.		Dispatch Inefficiencies
MTU	1.	b.	1	Significant problems with load-pockets.
MTU	1.	b.	2	Phase shifters and schedules are used to balance flows.
GEN	1.	b.	3	Redispatch could be used to relieve congested paths which could allow new generation (e.g., the West of McNary path; the I-5 corridor).
MKTR	1.	b.	4	Cutailments on BPA's Interties are used to relieve constraints on the Network even though PSANI studies indicated greater leverage (9:1) resulting from dispatching Network resources.
MKTR	1.	b.	5	See examples and extent of pre-scheduled curtailments on the BPA system: http://www.transmission.bpa.gov/OASIS/BPAT/outages/curtailments.htm
MKTR	1.	b.	6	Resources within 20 miles of COB still pay the full Network charge; wind projects face excessive transmission costs which deduct from a project's overall economics.
MKTR	1.	b.	7	Sales opportunities are mostly limited to designated PODs. Liquidity at these PODs would improve if the scope of the wholesale power market is expanded. Sales to the east are limited by congestion in Rocky Mountain region.
MKTR	1.	b.	8	Because of taxes, costs are different between Oregon and Washington in spite of similar fuel/heat rate. Preferred plant may not be able to participate in planned transaction due to transmission constraints.
MKTR	1.	b.	9	For deliveries in the Northwest region, respondent is minimally impacted by curtailments. For deliveries at greater distances, constrained paths often limit dispatch opportunities.
TDU	1.	b.	10	Because of complexities and transactional burdens of dealing with more than one tx system, we rarely source from supplies not available on/brought to the BPA grid.
MTU	1.	b.	11	When a bilateral transaction that would lower overall production cost faces a transmission tariff charge-much less multiple charges-the conventional method of fixed cost recovery can make the transaction uneconomic.
MTU	1.	b.	12	During real-time operation each control area is largely on its own, each essentially operating its own real-time market with its limited options, unable to utilize more efficient options (both supply-side and demand-side) that may exist in other control areas.
TDU	1.	b.	19	Respondent is generally deficit. While most resources are covered by firm transmission contracts within Host CA and adjacent Cas, respondent cannot access distant markets for resources with pancakes. Economic impact has not been evaluated.
MKTR	1.	b.	13	We have no resources that can be dispatched to relieve congestion and the physical location of these resources is almost always on the delivery side of congested paths.
TDU	1.	b.	14	We have sufficient access to resource stack and are unaware of any utilities that have even occasional difficulty attaining access to efficient generation.
GEN	1.	b.	15	Typically does not see inefficiencies regarding supply-side and demand-side dispatch within the Pacific Northwest.
TDU	1.	b.	16	We don't know of dispatch opportunities that are being missed; we have not been involved in any dispatch actions as we do not operate resources.
MTU	1.	b.	17	This is not a problem at this time.
MTU	1.	b.	18	No examples of existing inefficiencies of supply-side and demand-side dispatch.
	1.	c.		Under-utilization of Existing Transmission Facilities
MTU	1.	c.	1	Tx capacity mismatches at interfaces; the impact can be significant, e.g., 50% of import capability.
GEN	1.	c.	2	Significant amounts of transmission capacity has been contracted for, however, much is not used in actual operations and so could be available for new uses, e.g., Conditional Firm service.
MKTR	1.	c.	3	Transmission systems are under-utilized due to inconsistencies between posting/purchase timelines with trading deadlines and due to mismatched ATC.
MKTR	1.	c.	4	Economical transactions don't occur due to a lack of BPA RODS accounting accounts.
MKTR	1.	c.	5	BPA doesn't operate a functional OASIS site; it relies upon verbal communiction that underutilizes ATC; a recently released Inspector General Report confirmed this (February 2005).
MKTR	1.	c.	6	Unscheduled power flows through the respondent's parallel path transmission line limits the amount of capacity available for its own use. Respondent must allow more substantial TRM to ensure that capacity exists when it is needed for their firm service customers. Better management of parallel flows would allow increased, yet reliable utilization of capacity that is now held back as TRM.
GEN	1.	c.	7	Would be interested in knowing whether transmission is under-utilized during periods where schedules are curtailed.

				Problem Identification and Quantification Survey - preliminary results [draft_031105]
GEN	1.	c.	8	Rate and administrative pancaking results in transmission being under-utilized.
GEN	1.	c.	9	Mismatches between rights at the seams appears to leave transmission unusable.
TDU	1.	c.	10	We believe that the transmission system is generally underutilized.
MTU	1.	c.	11	There is a lot of evidence of under-utilized capacity (see SSG-WI PWG Path Utilization Reports). Paths can be fully subscribed with long-term contracts that are not used simultaneously.
GEN	1.	c.	12	Frequently there is underutilization of transmission capacity due to the flexibility allowed in contracts; capacity is "held out" in order to simultaneously honor all potential transactions.
GEN	1.	c.	13	There is a disconnect between planned and actual use of the transmission system; reducing headroom may result in more frequent curtailments of pre-existing rights.
MTU	1.	c.	14	Artificial limitations due to contract path schedules, or owned but unscheduled transmission rights (perceived to be inefficiencies due to “hoarding”) prevents the most economic dispatch that would be possible with a real-time energy market.
TDU	1.	c.	18	Respondent owns a share of line held in reserve without mechanisms to efficiently remarket the capacity.
TDU	1.	c.	15	We do not operate any transmission and are not aware of changes to facilities that could increase ATC.
MTU	1.	c.	16	Not aware of any systemic under-utilization of the transmission system.
MTU	1.	c.	17	No examples of underutilization of transmission capacity; more use out of existing facilities could be gained through new transmission service products.
	1.	d.		Effects of Congestion on Power Costs
MTU	1.	d.	1	Inefficient dispatch results from congestion - both in terms of out-of-merit dispatch and off-system power purchases.
MTU	1.	d.	2	Congestion is problematic in the Puget Sound Area and partially compensated, out-of-merit dispatch is used to relieve congestion (arrangement expires 3/2005).
MKTR	1.	d.	3	Congestion/curtailment of the Intertie causes significant economic consequences due to replacement/foregone transactions. Intertie curtailment subsidizes non-intertie network transactions.
MKTR	1.	d.	4	BPA doesn't credit firm transmission holders for derates that occur daily. See daily derates at: http://www.transmisison.bpa.gov/OASIS/BPAT/outages/houlry/hourlylimits.shtml
MKTR	1.	d.	5	During curtailments, curtailed schedules are not allowed to minimize economic losses with redirects; BPA forces customers to book-out the schedule or take-out the schedule.
GEN	1.	d.	6	Respondent has firm transmission for its plants. When using non-firm (sheltered) it is sometimes cut intra-hour due to firm customer calling on service. Primary concern is lack of timely notice on intra-hour cuts.
GEN	1.	d.	7	Respondent has needed to purchase replacement energy to accommodate transmission O&M planned that resulted in congestion.
GEN	1.	d.	8	Shutdown and startup costs should be considered in the economic analysis of congestion and curtailments.
GEN	1.	d.	9	Not a common problem given plant location and current congestion patterns. Aware that flow-based scheduling may change the situation.
GEN	1.	d.	10	Congestion does not cause the purchase of replacement energy for some customers but it does for some GTA customers (actual data is commercially sensitive).
TDU	1.	d.	11	See log of curtailment information.
MTU	1.	d.	12	Congestion that impedes efficiency is often a scheduling phenomenon, without any actual physical congestion on the grid. Such congestion can result in the use of more expensive resources (perhaps purchased from others) when a constraint does not physically exist on the grid.
GEN	1.	d.	13	Transmission congestion on the BPA Network is often resolved by cutting Intertie schedules. This disproportionately impacts transactions on the fringe, e.g., the Northern interconnection, the Pacific Intertie and the Montana tie. This approach to relieving congestion is a result of a lack of knowledge about how schedules, determined by contract path, affect constraints.
TDU	1.	d.	19	Respondent has had firm transmission curtailed, usually between June through August, because of transmission congestion, most often TOT-1A and Path “C”. Economic costs have not been quantified.
MTU	1.	d.	14	Has experience only a few hours where congestion prevented transmission service over a 20-year period. Price differentials across congested cutplane were nearly zero.

				Problem Identification and Quantification Survey - preliminary results [draft_031105]
TP	1.	d.	15	Not a significant problem.
TDU	1.	d.	16	Our production costs have not been affected by congestion.
TDU	1.	d.	17	We are able to optimize resources over 95% of the time; purchases and sales hampered by congestion are usually solved at no or little cost.
MTU	1.	d.	18	We don't see inefficiencies at this time, however, nonfirm curtailments do result in out-of-merit dispatch.
	1.	e.		Effects of Rate Pancaking on Resource Planning
MTU	1.	e.	1	Rate pancakes are pushing generation closer to load centers.
MTU	1.	e.	2	No examples of how transmission systems are being underutilized; however, limited transmission to get new resources to load affects planning decisions.
GEN	1.	e.	3	In specific cases, e.g., Snohomish PUD, pancaked wheels make renewable resources uneconomic.
MKTR	1.	e.	4	Ultimately a pure postage stamp or form of highway/zonal rate structure will best align system usage and cost recovery.
MTU	1.	e.	5	Resources located within one's control area have a built-in economic advantage; using multiple systems results in added economic hits as well as losses.
MKTR	1.	e.	6	Wind projects located in Washington/Oregon face congestion and rate pancakes which is one of the most difficult hurdles for these projects.
MTU	1.	e.	7	Pancaked rates reduce the competitiveness of potential respondents to RFPs; pancakes also influence the efficient siting of resources.
TDU	1.	e.	8	Transmission availability has more of an impact on resource planning than rates.
GEN	1.	e.	9	Rate pancaking affects the respondent's ability to compete in power supply acquisition processes of LSEs.
GEN	1.	e.	10	PBL has few examples of how rate pancakes affect long-term resource acquisition decisions. One example is wind however that information is confidential.
TDU	1.	e.	11	For service to our loads in non-BPA CAs we try to purchase power from the local utility or use federal power - pancakes limit our appetite for non-federal power. Lack of ATC, however, is the biggest problem these days.
TDU	1.	e.	17	Resource planning is limited to host control area. This limits the resource fuel diversity. Physical constraints on posted ATC also indicate that even if pancaked charges were reasonable, physical schedules would be affected limiting usability of the product.
MTU	1.	e.	12	Ascribing "inefficiency" to the incidence of rate panacking transmission services for long-term resources is premature.
TP	1.	e.	13	Not applicable. Respondent has surplus capacity/energy and has not been planning new resources.
TDU	1.	e.	14	Rate pancaking has not impacted our planning decisions.
TDU	1.	e.	15	Rate pancking has not affected long-term resource planning decisions.
MTU	1.	e.	16	No examples of ineffciencies regarding supply-side and demand-side resources.
	1.	f.		Other
MTU	1.	f.	1	Production costs have not been quantified.
GEN	1.	f.	2	Production cost information and the impact of pancaked rates could be extracted from Request for Proposal responses by wind and geothermal resource owners.
MTU	1.	f.	3	Local generation benefits from the present balkanized transmission system.
GEN	1.	f.	4	Lack of a stable, level playing field has made plant economics more difficult.
MTU	1.	f.	5	Control area boundaries currently present obstacles both in terms of transmission cost and scheduling coordination.
MTU	1.	f.	6	Market power or manipulation of market rules results in market distortions and inefficiencies.
	2.			**Transmission System Operations**
	2.	a.		Coordination of Transmission O&M
MKTR	2.	a.	1	Regional coordination considers the cost of outages but not the value; the impact of outages have been calculated.
MKTR	2.	a.	2	On the BPA system, there is a mismatch between planning outages and ATC available for short-term transactions. There should be one method for calculating ATC for outages.
MKTR	2.	a.	3	During curtailments, curtailed schedules are not allowed to minimize economic losses with redirects; BPA forces customers to book-out the schedule or take-out the schedule.
MKTR	2.	a.	4	BPA does not adequately explain why and the duration of path derates.

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MTU	2.	a.	5	Path issues are being resolved through cooperative efforts.
MTU	2.	a.	6	We have a comprehensive outage coordination process with internal stakeholders; there is a problem with posting 45-day advance notice for the BC-US path, as it limits accurate TTC postings.
TDU	2.	a.	7	Transmission outages always have the potential to impact the market and reliability. The current procedures seem wholly adequate.
TDU	2.	a.	8	Due to human error, coordination of outages is sometimes not perfect; better communication with our CA could reduce outage time on our generator.
GEN	2.	a.	9	PBL is involved in the NWPP 45-day outage planning process which notifies transmission users; CAISO does not participate (their outage information is received at preschedule). More active participation by CAISO would be an improvement.
GEN	2.	a.	10	There is a general lack of market concerns. For example, on the east coast, gas-nomination (alternative energy sources) is considered when O&M schedules are decided but not in the west.
GEN	2.	a.	11	The WECC pre-schedule calendar is driven by staff schedules rather than market concers.
GEN	2.	a.	12	There is a general lack of coordination amoung transmission providers that can cause significant problems for transactions involving more than one transmission, e.g., on the Intertie.
MTU	2.	a.	13	Current outage coordination procedures (NWPP COS) are adequate. It is not apparent that improved outage and maintenance coordination would substantially lower costs.
MTU	2.	a.	14	The current outage coordination used in the NW is effective in coordinating outages such that their impact on the commercial use of the transmission system is minimized.
G	2.	a.	15	Respondent has been unaware of outage coordination efforts that have affected transactions. Meaningful communication of outage impacts could be improved.
TDU	2.	a.	16	Transmission maintenance and associated outages are well coordinated and result in minimal or no impacts to delivery of energy.
G	2.	a.	17	No problems thus far.
TP	2.	a.	18	No problems with transmission outage coordination.
MTU	2.	a.	19	Transmission outages and maintenance procedures are adequately coordinated.
MTU	2.	a.	20	No problems with outage and maintenance procedures.
MTU	2.	a.	21	Current procedures are coordinated adequately.
TDU	2.	a.	22	Respondent's transmission provider performs live line maintenance or system is dispatched so that outage coordination is seldom an issue of service interruption. Respondent is also an NT customer (i.e. benefits from redispatch by TP).
	2.	b.		Inefficiencies and/or Barriers to Entry in Ancillary Services Markets
MKTR	2.	b.	1	There are barriers to entry in the AS markets due to technical requirements, flexibility limits and inconsistent business practices/systems.
MTU	2.	b.	2	Compensation for the provision of AS has partially been addressed by BPA, e.g., self-supply of reserves, generator-supplied reactive; compensation for RAS has not been addressed.
MTU	2.	b.	3	There are few technically defensible guidelines for locating operating reserves within the NWPP area; purchases from outside are at a distinct disadvantage.
MTU	2.	b.	4	Better understanding of locational requirements could lead to a regional reserves market that could lower overall costs.
MKTR	2.	b.	5	Procuring 3rd party AS under BPA agreements has proven technically/administratively burdensome; a reserves market is developing but it has taken 2 years and still requires BPA approval.
MKTR	2.	b.	6	Self-supply of generator reactive power has taken numerous years to consider; the proposed business practice severely limits the self-supply credit awarded (examples provided).
MTU	2.	b.	7	Pancaked transmission rates can create inefficiencies and barriers to entry; generation owners appear to be overly conservative due to obligation to serve native load.
MTU	2.	b.	8	We haven't had sufficient experience with facilitating an AS market; we anticipate that some market participants may sell to the major market player rather market themselves.
TP	2.	b.	9	Respondent currently purchases load following from a transmission owner/operator under its OATT. Additional options would likely be beneficial.
GEN	2.	b.	10	Some plants are subject to OATT contractual language that precludes the plant from selling ancillary services. Others are not.
GEN	2.	b.	11	Reactive power supply compensation has been an issue. There is some recent progress in this regard.
GEN	2.	b.	12	The operating reserves market does not work for merchant plants that are capable of providing service. Current OATT policy tends to favor transmission provider's affiliate. Restriction to provide on a one-year minimum contract basis limits opportunities.

				Problem Identification and Quantification Survey - preliminary results [draft_031105]
GEN	2.	b.	13	There are inefficiencies in the AS market due to the lack of compensation for standby capacity (energy imbalance), an inability to track capacity to justify compensation and, embedded cost rates preclude pricing to reflect market value. Barriers to the AS market include lack of market liquidity, lack of price transparency and customers' lack of experience with the markets.
GEN	2.	b.	14	Zonal scheduling will complicate measurements and tracking AS transactions; inc/dec dispatches between zones may allow pricing closer to market value and may solve current problems.
MTU	2.	b.	15	Reserve sharing is done strictly on a pro rata basis with limited regard for an economic approach to the provision of the associated capacity or energy.
MTU	2.	b.	16	The lack of real-time coordination between control area operations means that regional power requirements are very unlikely to be provided either as quickly, reliably or as efficiently as is possible.
MTU	2.	b.	17	The limited markets for ancillary services are less developed and are neither liquid nor well organized.
TDU	2.	b.	22	Self-provides all but Scheduling/dispatch. Has considered selling surplus, but is impractical given the current system configuration (behind the wholesale meter generators, e.g. reciprocating engines) and tariff. If there was a tariff service structure that valued distributed generating resources, it may be possible to derive value from these resources (e.g. demand response).
TDU	2.	b.	18	We don't have resources to invest in the AS market; most restrictions to date have resulted from IT systems.
TDU	2.	b.	19	We have not experienced any problems in this area.
MTU	2.	b.	20	No awareness of barriers to entry in the AS markets.
MTU	2.	b.	21	No awareness of barriers to entry in the AS markets.
	2.	c.		Comparability of Inadvertent Payback v. Energy Imbalance Charges
MTU	2.	c.	1	Inadvertent payback may become a problem forcing the creation of additional control areas.
GEN	2.	c.	2	Views the practice of inadvertent payback as unfair to those who must pay energy imbalance penalties.
MKTR	2.	c.	3	Inadvertent payback is tied to DJ index or posted "marginal prices" at a variety of points; there is no transparency and so no assurance charges are fair.
MKTR	2.	c.	4	BPA disallows imbalance payments for over-generation if BPA spills for a single hour at any of the federal projects; this practice is inequitable to generators.
MTU	2.	c.	5	The current process is inefficient due to the iterative manner CAs settle with adjacent CAs; reconciliation can take days to months to settle.
TP	2.	c.	6	Inadvertent payback and energy imbalance penalties are not comparable and a reasonable and comparable system for settling imbalances without penalties is desirable.
GEN	2.	c.	7	Respondent pays imbalance energy charges that are not comparable to inadvertent payback.
MTU	2.	c.	8	The current process for identifying and settling control error is efficient and adequate. Payback is divided into peak and non-peak periods so that energy is returned on like hours, thus effectively mitigating economic consequences associated with inadvertent payback.
GEN	2.	c.	9	We use time error correction to account for payback which is equitable and unbiased, efficient and affords comparable treatment among users.
MTU	2.	c.	10	Inadvertent payback is a reliablity issue and should not be considered a market use of the transmission system; the current process is efficient and offers comparable treatment.
MTU	2.	c.	11	Inadvertent is typically settled using WECC's time error correction process; firm is paid back within 3 hours; nonfirm may accumulate longer.
MTU	2.	c.	12	The current approach to inadvertant papyback is reasonably fair, however, it needs to be improved.
TDU	2.	c.	13	We do not operate a CA; we don't have an opinion about inadvertent accumulation or payback.
TDU	2.	c.	14	Imbalance payments are settled at an indexed hourly price. Respondent is able to both buy imbalance and sell imbalance to TP. Able to schedule within the deadband has not been charged penalties.
	2.	d.		Compliance with Dispatchers Orders
MTU	2.	d.	1	Scheduled cuts have been requested which are counter to the requested relief.
MTU	2.	d.	2	There is a lack of knowledge of how our system works which has led to curtailments that were not necessary.
MTU	2.	d.	3	Retail load reduction can be used, however, the process is ineffective.
TDU	2.	d.	4	To some degree: S>N capacity on the Northern Intertie has been curtailed when adequate redispatch was not available.
MKTR	2.	d.	5	We are aware of instances of non-compliance, e.g., January 30th, 2004 (PSANI).

				Problem Identification and Quantification Survey - preliminary results [draft_031105]
MKTR	2.	d.	6	There is a lack of continuity from one control area to another as to what is a proper NERC tag; tags are sometimes denied for syntax issues even when the denial caused reliability problems.
MTU	2.	d.	7	This is a rare occurance, but happens usually when a generator owner is reluctant to reduce output that is serving load across the constained path (Examples not available due to Confidentiality).
MKTR	2.	d.	8	There have been no circumstances when dispatcher instructions have not been followed, however, there have been instances when orders were implemented and the instructions were in error.
MTU	2.	d.	9	Not aware of dispatch orders not being complied with.
TDU	2.	d.	10	Not aware of dispatch orders not being complied with.
GEN	2.	d.	11	Dispatchers orders are obeyed to preserve reliability.
MTU	2.	d.	12	Respondent has not received a PNSC directive. In one instance the respondent's request that another utility curtail schedules was not followed. Respondent took action to ensure that system continued to operate within limits.
MTU	2.	d.	13	No specific instances, however, there have been occasions when real-time marketers have intially baulked.
MTU	2.	d.	14	We are not aware of any such instances.
TDU	2.	d.	15	Not aware of dispatch orders not being complied with.
TP	2.	d.	16	Not aware of any instances where orders were not complied with
MTU	2.	d.	17	Not aware of dispatch orders not being complied with.
TDU	2.	d.	18	No incidents. Control areas involved in respondent's transactions have sometimes had issues.
	2.	e.		<u>Effectiveness of Dispatchers Orders</u>
MTU	2.	e.	1	Scheduled cuts have been requested by other systems without any impact on congestion and without re-instating the schedules.
MTU	2.	e.	2	Scheduled cuts have been requested by other systems without any impact on congestion and without re-instating the schedules (Examples provided).
TDU	2.	e.	3	This was a problem with Seattle; had Seattle complied with the request, the request would not have relieved the loading.
TDU	2.	e.	4	Without the ability to monitor line loadings it is not possible to determine whether re-dispatch works or not.
MKTR	2.	e.	5	There have been no circumstances when dispatcher instructions have not been followed, however, there have been instances when orders were implemented and the instructions were in error.
TP	2.	e.	6	Some instances of curtailments have raised questions, but no dispute resolution procedures have been invoked.
MTU	2.	e.	7	Respondent is unaware of any dispatch orders that failed to provide relief when followed.
MTU	2.	e.	8	This occurs periodically but it is difficult to determine whether it is a result of intentional failure or untimely implementation of the right process/procedure (Examples provided).
MTU	2.	e.	9	Problems occur when generation that needs to be dispatched is not controlled by the CA having loading problems, or as a result of obsolete data or lack of interchange schedules.
TDU	2.	e.	10	We are not aware of any such instances.
MTU	2.	e.	11	We are not aware of any such instances.
MTU	2.	e.	12	Not aware of dispatch orders failing to relieve loading problems.
MTU	2.	e.	13	Not aware of dispatch orders failing to relieve loading problems.
	2.	f.		<u>Other</u>
MTU	2.	f.	1	The time that current curtailment procedures take to translate curtailed transactions into actual generation changes (that bring about the desired change in flow) is too long.
MTU	2.	f.	2	Strategic placement of additional phase shifting transformers for the WECC paid for by the entire interconnection would be helpful.
MTU	2.	f.	3	The Reliability Coordinator should have the tools to ensure proper generation re-dispatch occurs to effect necessary loading relief.
MTU	2.	f.	4	Over the last 10 years the amount and complexity of transmission transactions have increased, while the transmission facilities and interconnections between different owners' systems have remained largely unchanged.
MTU	2.	f.	5	Aging transmission facilities are expected to accommodate far more transactions today than they did a decade ago, while continuing to provide high levels of reliable service.

				Problem Identification and Quantification Survey - preliminary results [draft_031105]
GEN	2.	f.	6	The recently adopted "Curtailment Calculator" poses problems as it was developed without customer input and one of the flowgates it manages (Paul-Allston) relies upon 3 IPPs on a first priority basis. The "Curtailment Calculator" impacts the economics of certain power supplies and yet the method was developed without input from the entities it affects.
GEN	2.	f.	7	Changes to Business Practices that have commercial implications and appear discriminatory and inconsistent with the Transmission Provider's tariff are implemented without comment.
	3.			**System Capability and Scope**
	3.	a.		Impact of Reliability Policies
MKTR	3.	a.	1	Reliability policies should be changed to ensure that energy schedules are only cut for reliability purposes not for other reasons such as accounting.
MTU	3.	a.	2	Reliability policies too often address general situations without the technical basis or detail to support their strict application in all real world instances.
MKTR	3.	a.	3	There is a lack of continuity from one control area to another as to what is a proper NERC tag; tags are sometimes denied for syntax issues even when the denial causes reliability problems.
TDU	3.	a.	4	The WECC is on top of reliability policy and procedures; compliance monitoring and enforcement measures are appropriate, however, they are probably not adequate.
TDU	3.	a.	5	We have not experienced problems with reliability apart from short-term events.
GEN	3.	a.	6	The last on, first off component of RAS is not fair. Most recently constructed units may not be the most effective or economical form of relief.
GEN	3.	a.	7	Economic impacts have been more problematic than reliability standards and compliance.
GEN	3.	a.	8	Implementation of Operating Reserve requirements appears to be inconsistent among market participants. Control areas meet requirements in one way, but impose different standards on their transmission customers.
MTU	3.	a.	9	The reliability of the transmission grid is compromised by the existence of a large number of autonomous control areas without the ability to quickly and accurately communicate status and needs.
MTU	3.	a.	10	PNSC has a limited view of the region’s transmission system and, while it may be able to detect problems as they develop, is not in a position to know the cause of those problems due to limitations on the information it has available.
MTU	3.	a.	11	Coordination of multiple control area operations without sufficient transparency and appropriate authority can be an ineffective approach to reliability, as evidenced by the blackout of August 2003 in the Northeast.
MTU	3.	a.	12	WECC has developed reliability planning criteria that guide how one control area may affect the reliability of another, but these criteria do little to detail what reliability criteria the individual control areas must utilize internally.
MTU	3.	a.	13	WECC criteria is generally voluntary. RMS is limited to a few policies.
TDU	3.	a.	24	WECC RMS imposes costs on parties that cannot be responsible for flow impacts. Redispatch orders for WECC UFMP create conflicts between contract path and flow-based regimes.
MTU	3.	a.	14	The programs that protect the reliability of the transmisson system are NERC's Compliance Program and WECC's Reliability Management System program.
MTU	3.	a.	15	There is no long-term planning mechanism in place to ensure that short-term operating criterion is met without implementation of very drastic measures.
MTU	3.	a.	16	Enforceable resource adequacy standards will allow the 1980 Power Act mandate to be met by PBL even with a reduced power acquisition role going-forward.
MTU	3.	a.	17	The current NERC standard development process is robust, allowing for significant industry input and coordination to change or enhance reliability policies and practices. With respect to the current voluntary compliance structure, current monitoring and compliance programs appear to be appropriate and sufficient.
GEN	3.	a.	18	NERC's Version 0 (Operating Policy) and current policy are lacking in compliance, measurement and enforecement measures. Disaggregation of the generation function has distanced generation owners from responsibility and accountability. Greater transparency with regard to generation and load expectations could improve knowledge about transmission constraints.
TP	3.	a.	19	No changes suggested. Generally reliability standards are becoming more stringent in the aftermath of August 2003. Not clear whether the new standards will resolve problems or bring on new challenges.
TDU	3.	a.	20	Current reliability standards are adequate; it may be necessary to find ways to encourage those not following standards to do so.
MTU	3.	a.	21	Reliability criteria are established by NERC and WECC.
MTU	3.	a.	22	Reliability policies and practices in WECC have met or exceeded NERC standards.

				Problem Identification and Quantification Survey - preliminary results [draft_031105]
MTU	3.	a.	23	NERC Version O and WECC RMS are current compliance programs and both appear appropriate and sufficient at this time.
	3.	b.		Parallel Flow Effects on Transmission
MTU	3.	b.	1	Parallel paths may reinforce system reliability as well as create unscheduled flows.
MKTR	3.	b.	2	Parallel flows in the Puget Sound area impact the Northern Intertie which restricts the ability to secure Operating Reserves, increases risk of curtailment and increases lost revenues.
MTU	3.	b.	3	Transmission systems west of the Cascades experience N>S flows that are a result of parallel scheduling on transmission east of the Cascades.
MTU	3.	b.	4	Problems include but are not limited to: curtailments, reduction of generation levels and voltage problems resulting from unscheduled flow from outside our CA (Examples provided).
MTU	3.	b.	5	Our approach is to mitigate parallel flows with RAS rather than limiting pre-outage flows, thus minimizing the economic impact. (Examples provided).
MTU	3.	b.	6	The parallel flow at the BC-US boundary is controlled with the Nelway Phase Shifter; this can reduce the import capability from Alberta and the US and creates congestion in the BC interior.
TDU	3.	b.	7	Parallel flows have a tendency to lower the overall ATC of a given path; we can't tell if parallel flows have impacted schedules.
TDU	3.	b.	8	Parallel flow issues between BPA and PAC result in higher transmission costs to us; the costs are minor and we are satisfied with the situation.
TP	3.	b.	9	loop flow.
TP	3.	b.	10	Parallel flows could limit owner’s ability to fully utilize capacity of its line since capacity to cover unscheduled, parallel flows must be held back as TRM.
TP	3.	b.	11	Path is rated at 645 MW (minus 80 for TRM), leaving 565 MW usable.
TP	3.	b.	12	The Unscheduled Flow Mitigation Procedure (UFMP) does not consider economics. Cost and impact on the path should both be considered.
GEN	3.	b.	13	Parallel flows could create congestion that results in curtailment of firm service.
MTU	3.	b.	14	From time to time the respondent experiences parallel flow issues related to its interconnections with neighboring systems during high hydro, warm temperatures, and high load conditions. The economic consequences (e.g. effect upon wheeling revenue) resulting from these parallel flow impacts are not substantive.
MTU	3.	b.	15	Reservation and scheduling practices are problematic given the fact that transmission has historically been sold based upon contract-paths but power flows on the path of least resistence.
MTU	3.	b.	16	There are seams problems when interconnected systems that use different methods (flow-based and contract path) calculating use and ATC.
GEN	3.	b.	17	In some cases, system operators have agreements in place that allow "redispatch" and sub-optimal unit and basin-wide efficiency. Barring redispatch, curtailment results in liquidated damages.
MTU	3.	b.	18	During severe system disturbances originating in other systems where no timely action is taken by the entities experiencing the disturbance, other interconnected entities can be subjected to RMS-related violations for which they are not responsible and over which they have no control.
TDU	3.	b.	22	Loop flow results in higher losses and occaisional curtailment of firm deliveries.
GEN	3.	b.	19	Not aware of any impacts from parallel flows at their location.
TDU	3.	b.	20	Parallel flows may be an issue but they are never an issue for us delivering low cost Federal Generation to our loads.
MTU	3.	b.	21	Parallel flow is not an issue due to use of phase shifters.
	3.	c.		Failure Propagation and RAS
MTU	3.	c.	1	We don't see RAS as a problem but instead, a cost-effective means of maintaining ATC. However, RAS cannot supplant all needed construction and upgrades.
MTU	3.	c.	2	RAS, especially for coal plants, could result in significant plant damage. In addition, RAS causes immediate loss of energy sales and affects economics.
MKTR	3.	c.	3	Our experience with RAS has been minimal with few actual incidences of tripping. Standards vary throughout the west as to how much RAS should be relied upon which may be problematic.
MTU	3.	c.	4	Programs to control failure propagation, which we assume to be safety nets, could be enhanced by an organization that has a wider geoographic scope.
MTU	3.	c.	5	RAS schemes can be an inexpensive method to increase ATC, however, these schemes impact the generator owners. More frequent curtailments occur without RAS.

				Problem Identification and Quantification Survey - preliminary results [draft_031105]
MTU	3.	c.	6	Transmission upgrades and additions are deferred in favor of more complex RAS; RAS are increasingly more difficult for operators to apply in real-time (Examples provided).
MTU	3.	c.	7	Generators participating in RAS are concerned with direct costs, the equity of cost recovery and equity of allocation of benefits.
TP	3.	c.	8	Respondent has RAS on its generating plants. Must have to protect the 138 kV lines in parallel with the 345 kV lines. Without RAS, the transmission capacity would be reduced to 300 MW.
GEN	3.	c.	9	Instances have occurred where outages are planned that cause constraints resulting in armed RAS. Respondent has not been informed on a timely basis that RAS was armed and transactions were at risk.
GEN	3.	c.	10	Trips versus runbacks. Tripping entire unit is not appropriate in situations where partial runback would provide relief.
GEN	3.	c.	11	Initially respondent's powerplant was not required to implement RAS. After project was 90% completed, transmission provider informed respondent that RAS would be required at a cost of $2.5 M. Respondent was able to implement an acceptable RAS for $500,000.
GEN	3.	c.	12	Has plant equipped with RAS that has not operated. Not sure if it has been armed.
GEN	3.	c.	13	Some generators are required to implement RAS whereas others are not in spite of similar ability.
GEN	3.	c.	14	If RAS trips plant, maintenance cycle is shortened (increases equivalent operating hours). A full load trip causes a significant amount of equivalent operating hours.
MTU	3.	c.	15	Remedial action schemes are often a cost-effective means to increase total or available transmission capacity. Without RAS the total transfer capability on many paths would be significantly reduced.
MTU	3.	c.	16	RAS can also be used as a safety net to enhance reliable system operation by providing a means of surviving unplanned failure events.
MTU	3.	c.	17	RAS alternatives are regularly and consistently incorporated into planning and operational studies in order to determine the most economical means of increasing the capability and enhancing the reliability of the region’s transmission system. Accordingly, it is not apparent that any RAS opportunities are being overlooked.
GEN	3.	c.	18	While certain remedial action schemes may have a deleterious effect upon generation equipment, it is clear that RAS is often a cost-effective means to increase transfer capability on a transmission system.
GEN	3.	c.	19	In many cases, a RAS offers a plant owner an economically affordable alternative to funding new transmission line construction. Accordingly, even for generation resources participating in a RAS, it generally has a positive economic effect upon operations.
TDU	3.	c.	20	We are not involved in RAS.
GEN	3.	c.	21	For the transmission customers, there is benefit in having the system operator use RAS as it can increase ATC. Current PNW programs are adequate except in terms of accounting for system changes.
MTU	3.	c.	22	We see no problems associated with control failure propagation schemes.
MTU	3.	c.	23	We don't know about the economic ramifications of RAS.
TDU	3.	c.	24	Respondent depends on RAS for capacity on its jointly owned line.
	3.	d.		TTC/ATC Determination
MTU	3.	d.	1	ATC issues at interconnections and CAISO in particular.
MKTR	3.	d.	2	ATC is poorly coordinated between adjacent control areas; the Southwest ties are particularly problematic. Some Transmission Providers don't post ATC which results in a lack of transparency.
MTU	3.	d.	3	There is a lack of coordination in the establishment of TTC on the Intertie which results in over curtailment because BPA and the CAISO direct parallel but non-congruent curtailment schedules.
MTU	3.	d.	4	It is inefficient for each Transmission Provider to separately calculate ATC; a single methodology should be generally adopted and should post to a common OASIS.
MKTR	3.	d.	5	Schedules on the BPA and PAC systems have been curtailed based on erroneous dispatcher instructions during the ramp forcing receiving CAs to start peakers to cover lost import energy.
MKTR	3.	d.	6	Economic transactions don't occur due to a lack of BPA RODS accounting accounts.
MKTR	3.	d.	7	BPA doesn't operate a functional OASIS site; it relies upon verbal communiction that underutilizes ATC; a recently released Inspector General Report confirmed this (February 2005).
MTU	3.	d.	8	Different approaches to calculating ATC on the Montana-Southwest path have posed problems.
MTU	3.	d.	9	We consistently apply the NERC/WECC rules and criteria, however, the BC-Alberta intertie is operated below the WECC path rating due to constraints imposed by the AESO.
TDU	3.	d.	10	The most common problem for us occurs on the Montana-Northwest Intertie; the transfer capability is limited (BPA ATC calculator) when congestion appears to be on the West of Hatwai path.

				Problem Identification and Quantification Survey - preliminary results [draft_031105]
GEN	3.	d.	11	No specific instances. Not possible to second guess transmission provider's calculations.
GEN	3.	d.	12	Perceives that ATC calculations are difficult to verify. Would prefer an independent evaluation of ATC on a systemwide basis with auditability provisions.
GEN	3.	d.	13	Recent implementation of a flow-based ATC determination methodology by a major transmission provider has hindered the ability to obtain firm transmission service across portions of their system where, under a contract-path approach recognizing scheduling constraints, firm transmission would likely be available. Other than this recent change in policy by a single transmission owner, we are not aware of any examples of differences or inconsistencies in the determination of ATC among the rest of the region's transmission providers.
GEN	3.	d.	14	We have had to reduce generation as a result of ATC reductions as a result of ATC discrepancies between TBL and CAISO. The result was inefficient operations.
GEN	3.	d.	15	When ATC is sold, we can't tell is the service is firm or reliable.
TP	3.	d.	16	Not affected.
MTU	3.	d.	17	We are not aware of problems with ATC calcuations.
TDU	3.	d.	18	Does not do many long distance transactions and estimates little impact from ATC postings.
	3.	e.		<u>Differences and/or Inconsistencies in OASIS, Reservation, Scheduling and E-Tagging</u>
MTU	3.	e.	1	Staffing for scheduling annd E-tagging is about $200,000/year.
MKTR	3.	e.	2	Differing reservation procedures among Transmission Providers is a problem when a transaction involves more than one leg. Also, some control areas do not coordinate TTC.
MTU	3.	e.	3	Transactions involving multiple legs present problems due to different ATC methods, multiple OASISs and changed policies that prohibit stacking more than one scheduling entity on one tag.
MTU	3.	e.	4	The requirement to tag before scheduling (and learning whether there is adequate ATC) is a problem.
MKTR	3.	e.	5	There is a lack of continuity from one CA to another regarding NERC tag configuration; the same tag can be accepted by some dispatchers and rejected by others.
MKTR	3.	e.	6	BPA OASIS inefficiencies, line derates, missing RODS accounts and inconsistent tag approval process costs us hundreds of thousands of dollars/year.
MTU	3.	e.	7	BPA may not wait enough time before curtailing scheduled transmission; it appears to ignore counter-flows and real-time conditions.
TP	3.	e.	8	There would be benefits of consistent, regional OASIS.
GEN	3.	e.	9	OASIS does not allow respondent to see the impact of the sum total effects of system conditions on its operating status making it difficult to assess curtailment risk on transactions.
GEN	3.	e.	10	With respect to COB/NOB transactions across the seam with CAISO, the two path operators have simultaneously cut transactions in a way that effectively results in twice the curtailment required to relieve the constraint.
GEN	3.	e.	11	E-Tagging has been inconsistently administered by operating entities. E-Tags could be handled more efficiently by a single, independent authority.
MTU	3.	e.	12	The impact resulting from differences among transmission providers' OASIS sites and procedures is negligible. Additionally, to the extent any such differences have created negligible impacts, the recent transition of much of the region to a common OASIS platform is helping to mitigate even these negligible impacts.
TDU	3.	e.	13	We deal with a limited number of OASIS sites; once the differences in navigating the different sites has been mastered, there is not much of a problem.
MTU	3.	e.	14	We are not aware of problems with OASIS, reservation schedules, etc. Most Transmission Providers use OATI and service is consistent and efficient.
TDU	3.	e.	15	Supports WestTrans.net as the OASIS.
TDU	3.	e.	16	Supports tagging for check-out and transaction verification.
	3.	f.		<u>Impact of TRM/CBM</u>
MKTR	3.	f.	1	TRMs appear to be excessively conservative and the cause of discrepancies of ATC determinations on two sides of a tie.

				Problem Identification and Quantification Survey - preliminary results [draft_031105]
MKTR	3.	f.	2	TRM and CBM provide the Transmission Provider with a mechanism to withhold ATC from the market and the application of TRM and CBM seems to differ from TP to TP.
MKTR	3.	f.	3	BPA's take-or-pay policy on firm transmission rights results in frequent derates in the name of reliability; this is inconsistent with other CAs. Credit for inaccessible firm rights should be mandatory.
MTU	3.	f.	4	We are part of the NWPP Reserve Sharing group and follow Contingency Reserve Sharing Procedures. We have numerous examples of how we have been impacted by TRM and CBM.
TDU	3.	f.	5	After outages in the summer of 1996, the capacity of the Intertie was reduced; the capacity has still not been restored to those who paid for it.
TDU	3.	f.	6	Some of the West of Hatwai congestion is the result of CBM.
GEN	3.	f.	7	Difficult to verify that margins are correctly established. Independent verification of these margins could improve confidence.
GEN	3.	f.	8	Not sure. Would prefer independent, auditable entity that applies a single, consistent approach to TRM/CBM calculations.
TDU	3.	f.	9	We have benefitted from both TRM and CBM because they have kept our costs down.
TP	3.	f.	10	Respondent established a TRM to ensure that its firm schedules are not cut. Parallel flows can increase unscheduled loading on line.
GEN	3.	f.	11	Respondent has not been negatively impacted by implementation of any Transmission Reliability Margins and/or Capacity Benefit Margins on other systems.
GEN	3.	f.	12	CBM and TRM are instruments used to insure reliable system operations; we believe that tariff and Business Practices define these margins and that they are fair and defendable and part of the cost of having a reliable system.
MTU	3.	f.	13	TRM and CBM are necessary to ensure reliable services.
MTU	3.	f.	14	We are not aware of how we have been impacted by TRMs and CBMs.
TDU	3.	f.	15	Not affected.
	3.	g.		Does E-Tagging Apply to All Schedules?
MTU	3.	g.	1	We are required to submit E-tags for all scheduled transactions.
MTU	3.	g.	2	The tagging requirement applies to all scheduled transactions.
MKTR	3.	g.	3	We are required to submit E-tags for all energy schedules that cross control area boundaries and for some internal schedules.
MTU	3.	g.	4	We are required to submit transaction tags for energy schedules except for dynamic schedules.
MTU	3.	g.	5	We require our transmission customers to comply with WECC E-tagging requirements.
MKTR	3.	g.	6	Yes and yes.
MTU	3.	g.	7	Yes, we require E-tags for all energy schedules.
TDU	3.	g.	8	We are required to submit E-tags for all scheduled transactions.
TP	3.	g.	9	Yes.
GEN	3.	g.	10	Yes. Respondent is required to submit E-tags for 100% of the energy delivered from its projects.
GEN	3.	g.	11	Purchaser is ultimately responsible for the E-Tag, but all energy sold from plant must be tagged.
GEN	3.	g.	12	Respondent is required to submit transaction tags for energy schedules, but is not required to submit transaction tags for resources within its control area providing service to retail native load.
GEN	3.	g.	13	In accordance with WECC policy, we are required to tag all schedules for which we are responsible. Much of our Network load stays within the TBL CA and does not require scheduling or tagging.
TDU	3.	g.	14	Yes.
TDU	3.	g.	15	Respondent tags only transactions that cross control area boundary. Would like something similar to a tag for internal accounting or require energy tagging for all energy transactions regardless of whether or not it crosses control area boundaries.
	3.	h.		Other
MTU	3.	h.	1	With centralized scheduling and availability of comprehensive system data on a flow basis, the region would be able to more accurately predict usage and would be able to facilitate additional usage.
MTU	3.	h.	2	Accounting for system uses on a basis aligned with the actual physics of the system would allow for more accurate prediction of transmission flows and reliability performance, and the determination of rights and costs from expansion with more predictability and precision.
	4P			**Existing Transmission Constraints - TPs**

				Problem Identification and Quantification Survey - preliminary results [draft_031105]
	4P	a.		Flowgate/Path Limitations on Transactions
MTU	4P	a.	1	All tie-lines are constrained and are posted.
MTU	4P	a.	2	Our company's Transmission Provider posts paths regardless of their "constrained" status; ATCs are automatically calculated once/day.
MTU	4P	a.	3	We post 11 paths, 6 of which are constrained.
MTU	4P	a.	4	We post interconnections with all adjoining transmission systems.
MTU	4P	a.	5	We have tested the market's interest in capacity expansion through an Open Season offer (Example provided).
MTU	4P	a.	6	We post all commercially sensitive paths; path postings are updated every 5 minutes (OASIS example provided).
TP	4P	a.	7	Respondent is able to post some capacity held for TRM as interruptible to increase utilization of the line.
MTU	4P	a.	8	While it is not clear what is intended by the term “constrained” in this case, it is assumed that this refers to those paths where ATC is less than or equal to 25% of TTC during a given time period. Respondent posts all paths associated with its transmission system, regardless of the ATC on the path (zero to 100% availability).
MTU	4P	a.	9	BPA started posting paths in 1997 (6). Now BPA posts 17 paths.
	4P	b.		Capacity De-ratings and Pre-schedule Limits
MTU	4P	b.	1	De-ratings occurs due to outages that last more than one hour.
MTU	4P	b.	2	Pre-schedule curtailments occur primarily on the BPA system (See: http://www.transmission.bpa.gov/orgs/opi/interite/index.shtm).
MTU	4P	b.	3	We cannot provide all instances of transmission capacity deratings, however, we can tabulate the hourly pre-schedule limits by hour for our share of the Intertie.
MTU	4P	b.	4	Reductions of customer schedules do not occur often and when they do, it is a result of equipment outages or because of unscheduled flow.
MTU	4P	b.	5	The outage that occurred in the NW in the 1990s resulted in WECC adding criteria in the OTC study process. As a result, ratings have been reduced dramatically (Example provided).
MTU	4P	b.	6	Rating criteria is defined by the regional reliability governing body and so a regional transmission entity such as Grid West will not affect OTC.
MTU	4P	b.	7	We have attached information listing all instances of reductions in customer schedules from 2002 to present.
TP	4P	b.	8	Sales of transmission is made on a generating unit-contingent basis. De-ratings and limits coincide with planned outages.
MTU	4P	b.	9	The schedule cuts that typically occur on the respondent's transmission system are a result of the loss of specific facilities in a designated path. Where a path or interconnection consists of a single facility, schedules must be cut to zero in the event the facility is placed out of service, either due to a forced outage or for maintenance.
MTU	4P	b.	10	Schedule restrictions on certain facilities may be necessary during certain operating conditions in late spring or summer operating conditions. Any such de-rates have negligible impact on transmission wheeling revenue.
MTU	4P	b.	11	See attached materials regarding the instances of transmission capacity deratings (Examples provided).
	4P	c.		Real-time Curtailments
MTU	4P	c.	1	Pre-schedule curtailments occur primarily on the BPA system (See: http://www.transmission.bpa.gov/orgs/opi/interite/index.shtm).
MTU	4P	c.	2	We cannot provide all instances, however, we can tabulate the difference between customers' hourly pre-schedules and final real-time hourly schedules.
MTU	4P	c.	3	We have attached information listing all instances of reductions in customer schedules from 2002 to present.
TP	4P	c.	4	Curtailments are usually caused by unscheduled parallel flows that result in lines reaching their operating limit.
MTU	4P	c.	5	Real-time curtailments would have occurred only in the event of a forced outage on the lines noted.
MTU	4P	c.	6	Most real-time curtailments are in response to actual power flow exceeding the OTC; we don't have consistent information on what actions were taken when OTC was violated.
MTU	4P	c.	7	A log of OTC violations for 2004 is attached.
	4C			**Existing Transmission Constraints - TCs**
	4C	a.		Use of Flowgates and Posted Paths
MTU	4C	a.	1	We have interest in purchasing capacity that is affected by known (9) flowgates. Infrastructure additions will be needed to remove constraints.
GEN	4C	a.	2	The paths that affect wheeling wind generation include: West of McNary, Paul-Allston, Allston-Keeler and the I-5 corridor.
MKTR	4C	a.	3	Any flowgate that is congested will impact desired transactions; there are numerous in the WECC.
MTU	4C	a.	4	Capacity ratings are impacted by the use of different input data for calculating ATC and cutting intertie ratings in order to manage internal network constraints.
MTU	4C	a.	5	Any transaction moving into Portland from the North or East is impacted; existing rights cannot be redirected without congestion.

				Problem Identification and Quantification Survey - preliminary results [draft_031105]
MKTR	4C	a.	6	There are 20-30 paths around the west that "impact desired transactions." (Examples provided)
GEN	4C	a.	7	Purchases transmission from generating projects to Mid-C, COB/NOB, and also uses service to provide power to many load serving entities in the region.
GEN	4C	a.	8	Intertie with California is the critical path.
GEN	4C	a.	9	Commercial constraints on the West-of-McNary and West-of-Slatt paths are inhibiting the LSE's ability to acquire desired long term firm transmission. Respondent's LSE has also experienced constraints on the Montana-to-Northwest path.
GEN	4C	a.	10	The posted paths on TBL's system sometimes impacts PBL; usually, different paths are impacted during different seasons, e.g., West of Hatwai and the Northern Intertie. Limitations are expected to increase which will cause imposed limits on generation, redispatch and curtailment.
GEN	4C	a.	11	For all restricted paths we either have to reroute energy, buy behind, sell in a cheaper market or redispatch resources to move energy to load/market. On the TBL system, we manage transactions over 15 paths/areas; we manage two paths in Idaho and one on the Sierra Pacific system.
GEN	4C	a.	12	There constrained paths are a fluid phenomenon rather than fixed.
TDU	4C	a.	16	TOT-1A (Mona-Craig): occasional loop-flow; WACM, DGT, PacifiCorp; TOT-2A (4CRNS); APS, PNM, PacifiCorp; Path "C" (BOBR); IPC and PacifiCorp; Path 66: affected by UFMP
TDU	4C	a.	13	This is not an issue for us.
TDU	4C	a.	14	We do 99% of our business on the BPA transmission system and OASIS; there are 5 paths that are periodically constrained that we are mindful of.
TDU	4C	a.	15	We have not been affected by flowgates or posted paths.
	4C	b.		<u>Capacity De-ratings and Pre-schedule Limits</u>
MTU	4C	b.	1	We do not quantify all instances of transmission capacity deratings and pre-schedule limits. We experience constraints on 7 paths and cite 7 causes for such.
MKTR	4C	b.	2	BPA's policy of curtailing Intertie capacity rights holders "across-the-board" in pre-schedule, rather than actual schedules, has come at a significant economic cost.
MKTR	4C	b.	3	Capacity curtailments in pre-schedule is often reinstated in real-time which undermines the intial schedule.
TDU	4C	b.	4	It is impractical to detail each occurrence.
GEN	4C	b.	5	Need to look at COB/NOB curtailments. Planned and unplanned outages appear to be having a significant and ongoing impact on transactions. In spite of cuts, customers are still paying full contact amounts for transmission service.
GEN	4C	b.	6	Respondent's LSE has experienced the imposition of schedule limits as a result of a forced outage or planned maintenance outage of specific facilities. When a path or interconnection defined by a single facility is out of service, all schedules along such path are necessarily reduced to zero and other transmission alternatives must be acquired.
GEN	4C	b.	7	Capacity deratings of the Southern Intertie have occurred, limiting the opportunity for respondent's LSE to make sales of surplus energy to the south.
GEN	4C	b.	8	This information is not well tracked; it would take a lot of time to complie and is commercially sensitive.
TDU	4C	b.	9	See log of curtailment information.
TDU	4C	b.	10	At times, capacity on the Intertie is cut resulting in schedule and delivery reductions; the impact has been absorbed by the customer and so we don't know what the impact has been.
TDU	4C	b.	11	We have experienced schedule reductions time to time, mostly on the AC Intertie. The reductions are infrequent and mostly resolved through take-or-pay arrangements and redispatch.
TDU	4C	b.	12	We have only been affected by deratings caused by force majeure.
TDU	4C	b.	13	Happens occasionally but is not tracked and impacts are not known.
	4C	c.		<u>Real-time Curtailments</u>
MTU	4C	c.	1	We do not quantify all instances of transmission capacity deratings and pre-schedule limits. We experience constraints on 7 paths and cite 7 causes for such.

				Problem Identification and Quantification Survey - preliminary results [draft_031105]
MKTR	4C	c.	2	Real-time curtailments on the JD-COB path are too numerous to gather. BPA consistently derates JD-COB; Big Eddy-NOB and east to west flows.
MKTR	4C	c.	3	BPA requires tags prior to calling BPA to reserve ATC which causes schedules to be cut lat in the hour causing receiving CAs to scramble for energy during the ramp.
MKTR	4C	c.	4	BPA does not credit firm transmission holders for derates. Derates occur daily, see: http//www.transmission.bpa.gov/OASIS/BPAT/outages/hourly/hourlylimits.shtml
TDU	4C	c.	5	Since mid-2003, there have been a few curtailments on the Northern Intertie S>N and the total cost of redispatch has been less than $100,000.
GEN	4C	c.	6	Instances of non-firm service curtailments without notice are the most problematic.
GEN	4C	c.	7	Curtailments correlate with high prices thus increasing transactional risks.
GEN	4C	c.	8	Not clear whether curtailments are pro-rata on a fair basis.
GEN	4C	c.	9	Infrequent curtailments in the Northwest region, mostly due transmission forced outages.
GEN	4C	c.	10	This information is not well tracked; it would take a lot of time to complie and is commercially sensitive.
GEN	4C	c.	11	As long as Network congestion is relieved by curtailing Intertie schedules, inequities will persist.
GEN	4C	c.	12	There is a fluid determination of constrained paths which greatly complicates the determination of ATC, the service request process, and the firmness of the transaction.
GEN	4C	c.	13	Respondent's LSE has not undertaken any analysis to determine the number of instances and resulting impacts of any real-time curtailments. Any such instances and impacts would, however, be infrequent and minimal.
TDU	4C	c.	14	Most schedules that have been reduced are 25 MW or less and almost all curtailments have involved sales (not purchases).
TDU	4C	c.	15	We have not been curtailed except for force majeure.
TDU	4C	b.	13	Happens occaisionally but is not tracked and impacts are not known.
	5.			**Inconsistent Treatment of Generators/Loads**
	5.	a.		<u>Non-comparable Treatment of Reactive Power</u>
MTU	5.	a.	1	BPA is in the process of compensating providers of Generation Supplied Reactive; Grid West may assure customers a more balanced approach to compensation for services.
MKTR	5.	a.	2	Until recently, BPA has opposed compensating independent generators for reactive support while paying the PBL for very similar service. Even now, the payment to generators seems arbitrary.
MTU	5.	a.	3	Some non-comparable treatment among generators is appropriate, i.e., existing generation is paid for historical provision of reactive and new generation is paid incrementally.
GEN	5.	a.	4	Transmission provider affiliate's generators are compensated for reactive power, but respondent's generators are not.
GEN	5.	a.	5	While treatment may be non-comparable, respondent's powerplant is able to deliver full power at 85% power factor.
MTU	5.	a.	6	It is apparent that the allocation methodology used by BPA to determine the amount of generation-related costs allocated to Generation Supplied Reactive and Voltage Control produces an overstated allocation. No other transmission provider in the Grid West area, provides its affiliated resources with comparable cost allocation treatment.
GEN	5.	a.	7	The FERC has left unanswered many questions regarding compensation of reactive, e.g., pricing protocols, localized value, etc. TBL has negotiated a settlement to compensate some IPPs; PBL believes that reactive should be valued based on the benefit it provides for system stability and for the opportunity cost of the generation of useful energy that must be foregone to provide reactive.
TDU	5.	a.	8	BPA PBL is not subject to energy imbalance in serving full requirements customers' NT loads. We are subject to imbalance and BPA's 3-strike policy seems burdensome and arbitrary to those supplying AS.
TDU	5.	a.	9	We operate generation following good utility practice.
TDU	5.	a.	10	We have not experienced any problems in this area.
TP	5.	a.	11	Not an issue.
MTU	5.	a.	12	We don't have any examples of non-comparable treatment with generation-supplied reactive power.
	5.	b.		<u>Non-comparable Treatment of RAS</u>

				Problem Identification and Quantification Survey - preliminary results [draft_031105]
MTU	5.	b.	1	When the West of Hatwai cut place became oversubscribed due to loss of load on the east side, the Colstrip plants provided RAS without compensation; this issue was arbitrated.
MTU	5.	b.	2	We have two examples of non-comparable treatment of generation participating in RAS (involving West of Hatwai and Colstrip/Montana 1).
GEN	5.	b.	3	Several generators are not required to have RAS, yet they are equally situated to provide grid relief. Current practice appears to be installation of RAS only on new units.
GEN	5.	b.	4	Impacts of trip schemes versus runback is not considered. Trips have greater impacts on both cost and plant maintenance.
GEN	5.	b.	5	As a condition of interconnect, we have been required to provide RAS and do so without compensation. RAS is not secured or compensated in a consistent manner; providing RAS doesn't recognize market implications.
MTU	5.	b.	6	We know of no instance of non-comparable treatment of RAS imposed upon any of the respondent's generation relative to any other generation resource.
TDU	5.	b.	7	We don't own or operate any generation requiring remedial action schemes.
TDU	5.	b.	8	We have not experienced any problems in this area.
TP	5.	b.	9	Not an issue.
MTU	5.	b.	10	No generation RAS.
MTU	5.	b.	11	We don't have any examples of non-comparable treatment with RAS.
	5.	c.		Non-comparable Treatment (other)
MTU	5.	c.	1	All generation is required to provide voltage support.
GEN	5.	c.	2	Resources on the BPA Network benefit from the dispatch flexibility of the BPA resource system; this flexibility is not made available to non-Network resources.
MTU	5.	c.	3	The non-participating generators (in RAS) get preferred access to transmission. The risks include loss of energy, start-up costs and, increased damage to units.
GEN	5.	c.	4	There is a lack of comparability among participants in the AS market as a result of how business has been done in the past and therefore administrative systems are incapable of accommodating new market entrants. Therefore, there are problems in terms of who can participate in these markets, who is compensated and the level of compensation.
	5.	d.		Dispute Resolution for Non-comparable Treatment
MTU	5.	d.	1	It is inefficient for each Transmission Provider to separately calculate ATC; a single methodology should be generally adopted and should be posted to a common OASIS.
MTU	5.	d.	2	There is room for improvement in the way that TTCs for the N and S ends of the Intertie are curtailed; the net reduction (by BPA and CAISO) is usually more than what is actually required.
MTU	5.	d.	3	We haven't sought to have these inconsistencies addressed through dispute resolution.
GEN	5.	d.	4	Has not filed any fornal complaint but is included in settlement of reactive power supply case
GEN	5.	d.	5	We have been involved in a number of issues that have required litigaiton and negotiations; these attempts to remedy problems are expensive and inefficient.
GEN	5.	d.	6	Efficiencies are to be gained by having broad participation in problem solving so that broad interests are taken into consideration. In addition, identified solutions should be subject to broad comment.
	6.			**Tariff and Business Practice Confusion**
	6.	a.		Economic Inefficiencies Caused by
MTU	6.	a.	1	Changing rules at CAISO are hard to follow.
MKTR	6.	a.	2	Business Practices should be (but often are not) written to support the intent of the tariff rather than to accommodate system flaws.
MKTR	6.	a.	3	We have voiced complaints against transmission providers regarding business practice and tariff issues (FERC hotline, arbitration (NRTA, WRTA, WECC), FERC mediation and formal complaints.
MKTR	6.	a.	4	Shaped service is not consistently available, e.g., PAC offers it, BPA does not.
MKTR	6.	a.	5	Tariff concepts such as "Extensions of Commencement of Service" are not consistently interpreted (some allow extensions for annual or partial year, others in annual increments only).

				Problem Identification and Quantification Survey - preliminary results [draft_031105]
MKTR	6.	a.	6	Some applied the Extension of Commencement of Service to already contracted for transmission triggering bumping/matching procedures. This issue was resovled through (expensive) arbitration.
MKTR	6.	a.	7	There is a great deal of confusion about when redispatch should be implemented; criteria among TPs are not consistently applied.
MKTR	6.	a.	8	Operators throughout the west, operating under Order 888 tariffs have totally different requirements for providing ancillary services such as losses.
FU	6.	a.	9	The tariff language is loose regarding the procedures to implement Network Secondary transmission which has resulted in interruption and capacity going unused.
GEN	6.	a.	10	Operating reserves. Business Practice for self-supply is unworkable. Control areas can pool through NWPP, whereas customers cannot. After six strikes, supplier is disqualified from self-supply provisions.
GEN	6.	a.	11	OATT contains many vague and unclear provisions. Business practices are only beginning to resolve these issues.
MTU	6.	a.	12	Answer pending.
MTU	6.	a.	13	Current transmission charges can be the deal-killer for wind plants. Intermittent resources need reliable access to the transmission system when the wind is blowing, without having to purchase physical transmission capacity for 100 percent of nameplate project output 8760 hour per year as is currently required.
GEN	6.	a.	14	We have no such examples and have been engaged in no such proceeding (outside of BPA rate case proceedings).
TDU	6.	a.	15	We have not experienced any problems in this area.
TDU	6.	a.	16	We use BPA for 90% of our transmission requirements; we understand the tariff; Business Practices continually change; we have opportunities to comment; we have not disputed issues.
MTU	6.	a.	17	We have no examples of how confusion over tariff language, etc. has resulted in economic inefficiencies.
TDU	6.	a.	18	Repsondent has a grandfathered contract that works better than OATT for respondent's circumstances. Transmission tariff rates are concealed in the bulk of an OATT document making them difficult to find quickly or efficiently.
	6.	b.		<u>Pancaked Administrative Processes</u>
MTU	6.	b.	1	We don't know how much pancaked or multiple administrative processes have cost us.
MTU	6.	b.	2	If a transaction involves more than one transmission system, the processes of the owners do not automatically line up. This mismatch causes queue problems and study costs.
MKTR	6.	b.	3	There is a lack of continuity from one CA to another regarding NERC tag configuration; the same tag can be accepted by some dispatchers and rejected by others.
MKTR	6.	b.	4	Economical transactions don't occur due to a lack of BPA RODS accounting accounts.
MKTR	6.	b.	5	BPA doesn't operate a functional OASIS site; it relies upon verbal communiction that underutilizes ATC; a recently released Inspector General Report confirmed this (February 2005).
MKTR	6.	b.	6	BPA OASIS inefficiencies, line derates, missing RODS accounts and inconsistent tag approval process costs us hundreds of thousands of dollars/year.
GEN	6.	b.	7	PBL pays roughly $40-50 million/year to purchase 3rd party transmission services in order to deliver federal power to load.
MTU	6.	b.	8	Respondent and other transmission users experience multiple wheeling fees, transactional costs, and logistical obstacles in obtaining rights to move energy through multiple transmission owners' systems (i.e. pancaking).
GEN	6.	b.	9	The impact to respondent resulting from any multiple administrative processes is negligible.
TDU	6.	b.	10	We have been unaffected by pancaking or multiple administrative processes.
TDU	6.	b.	11	We have limited transactions that involve pancaked rates; we try to avoid these situations unless the cost of energy negates the extra charge.
TDU	6.	b.	12	Generally not applicable. Limited amount of long distance transmission service required.
	6.	c.		<u>Customers: Cost of Multiple System Requests and Schedules</u>
MTU	6.	c.	1	If a transaction involves more than one transmission system, the processes of the owners do not automatically line up. This mismatch causes queue problems and study costs.
MKTR	6.	c.	2	When a request for capacity involves multiple system and some portion involves a constraint, additional costs may be incurred (stranded transmission rights, additional transmission costs).

				Problem Identification and Quantification Survey - preliminary results [draft_031105]
MKTR	6.	c.	3	Even when transmission capacity is available, it is rare when a transaction can absorb more than one transmission chargee (two or more pancakes kill the economics of any transaction).
GEN	6.	c.	4	Often takes too long to build full account from source to sink. Have to build multiple accounts for every source to sink "deal", but can only do during normal business hours. Transaction is contingent upon all-or-nothing.
GEN	6.	c.	5	Unauthorized increase penalties are difficult to verify.
GEN	6.	c.	6	In real-time it is difficult to get all of the process steps completed for transactions that cross seams. Result is that power is sold to NW hubs where it is picked up and sold across the Intertie. Scope of market becomes limited by middlemen.
TDU	6.	c.	7	If these isn't ATC, requests are rejected; We have requested firm ATC and can only secure nonfirm service. It is difficult to quantify these costs.Constraints over other system cause us to not even access market supplies for power.
GEN	6.	c.	8	The inefficiency that we often face is lack of consistency in ATC determinations among transmission providers which is not an uncommon problem throughout the western interconnection.
GEN	6.	c.	9	Respondent has no examples of inefficiencies or additional costs, to date, resulting from inadequate ATC.
TDU	6.	c.	10	These situations are not of major concern.
TDU	6.	c.	11	We have not experienced any problems in this area.
TDU	6.	c.	12	Intermittently makes requests. Mostly this is not a problem.
	6.	d.		Providers: Lost Opportunities due to Adjacent System Limitations
MTU	6.	d.	1	Events in California can impact COI; inter-regional transfer paths need to be coordinated for both path deratings and ATC restoration.
MTU	6.	d.	2	The derating that we have absorbed due to changes in WECC's OTC determination process costs us $7.5 million/year.
MTU	6.	d.	3	We are unable to sell up to the WECC path rating due to mismatches between TTC determinations.
GEN	6.	d.	4	Market inefficiencies resuilt due to a lack of consistency among Transmission Providers in terms of how they post ATC, allow reservation of capacity, award capacity, schedule capacity and interrupt capacity. Also, there is a lack of consistency among competition times, definition of "competing requests" and, implementation of the bumping market.
GEN	6.	d.	5	Further complications arise when Transmission Providers don't have a functional long-term OASIS. This greatly complicates the long-term queuing process and awards for service and has remained unresolved for the past 5 years.
	6.	e.		System Impact Studies
MTU	6.	e.	1	Performing SISs based upon place in the queue ignores the probability of completion for certain projects which causes unnecessary delays.
TDU	6.	e.	2	We may have looked at resources that existed on the other side of a congested path in the past; currently we only consider resources that do not require transmission over a congested path.
TP	6.	e.	3	Must chain together requests to process a request. For an AC network there is only one relevant set of Injection and Withdrawl points. Contract path based requests do not work. Need to get all parties and requested uses together for a single, coordinated study without economic bias to the assessment process..
GEN	6.	e.	4	The process was difficult and time consuming. There is no method by which parties with similar interests can share costs. Effectively the transmission provider is paid to do multiple studies which in some case could have been combined into a single study. This wastes time and TC's money.
GEN	6.	e.	5	Firm-Redirect service is typically contingent upon System Impact Studies. Experience has been unsatisfactory.
TDU	6.	e.	6	We have not experienced any problems in this area.
MTU	6.	e.	7	We do not have examples of how these studies have impacted resource decisions or instances where we are financially supporting studies that are being supported by others.
TDU	6.	e.	8	Has requested an SIS for option analysis. But has not lost opportunities due to SIS delays.
	6.	f.		Timeliness of System Impact Studies
MKTR	6.	f.	1	System Impact or Facilities Studies are not completed in a timely manner which results in foregone transactions (the BPA long-term queue has requests that started over 4 years ago).

				Problem Identification and Quantification Survey - preliminary results [draft_031105]
MTU	6.	f.	2	We have four examples of circumstances where SIS or Facilities Studies not timely completed resulted in declined service. In two of these cases, lost revenues resulted (Examples provided).
TP	6.	f.	3	It is often not possible to complete the study in 60 days.
TP	6.	f.	4	Due to loop flow, studies are impacted by other requests on different systems.
TP	6.	f.	5	Amount of time depends on the nature of the request. 10 MW is different from 1000 MW. There may be ways to operationally grant a 10 MW request.
GEN	6.	f.	6	Process is perceived as cumbersome, expensive, and has high degree of uncertainty regarding outcomes.
GEN	6.	f.	7	We have had significant problems with delayed system studies. Moreover, when the Transmission Provider delayed its response to a long-term request for service we were offered various, sequential alternatives that did not seem to follow any particular logic which we believe has led to inconsistent application of the tariff and queue-clearing inefficiencies. This has shaken our confidence in the service offers that are eventually made and raises particular concerns about Partial Service.
GEN	6.	f.	8	Many requests for service term before service offers are made.
TDU	6.	f.	9	Has requested an SIS for option analysis. But has not lost opportunities due to SIS delays.
TDU	6.	f.	9	We have not experienced any problems in this area.
TDU	6.	f.	10	There is no SIS that itself is causing us to forego any particular resource acquisition. There is a large queue on the BPA system that requires impact studies; an RTO may improve coordination.
MTU	6.	f.	11	We do not have examples of SIS or Facilities Studies that have not been completed in a timely manner.
	6.	g.		Effect of Request Processing Delays
MKTR	6.	g.	1	BPA's long-term queue has resulted in a number of foregone transactions, often, start-times are missed.
MTU	6.	g.	2	We have four examples of circumstances where SIS or Facilities Studies not timely completed resulted in declined service. In two of these cases, lost revenues resulted (Examples provided).
GEN	6.	g.	3	Delays that lead to withdrawn requests for service have resulted in missed opportunities.
TDU	6.	g.	4	We have managed our portfolio so to avoid congested paths.
GEN	6.	g.	5	Any delays in the processing of transmission requests have been associated with future transmission access; we have no examples of foregone transactions.
TDU	6.	g.	6	We have not experienced any problems in this area.
MTU	6.	g.	7	We do not have examples of how delays in processing requests has resulted in foregone transactions.
	7.			**Planning and Expansion**
	7.	a.		Consideration of Congestion Costs in Investment Decisions
MTU	7.	a.	1	Without the ability to purchase adequate transmission; utilities are forced to serve load with local resources even though this limits fuel diversity.
GEN	7.	a.	2	The Open Season process on the McNary-John Day 500-kV upgrade is a good example; this path is sold on a contract basis and there is no information regarding the cost of congestion.
MKTR	7.	a.	3	The lack of information about the cost of congestion affected regional discussions about the Puget Sound Area congestion and the Kangley-Echo Lake upgrade.
MKTR	7.	a.	4	Unfortunately, congestion and associated costs are not being formally tracked. Work-around procedures have been developed and when the problem arises, we focus on load service.
MKTR	7.	a.	5	The frequency with which we have to deal with curtailment has grown to a level that concerns us.
MKTR	7.	a.	6	If capacity isn't available on a desired path, there is little information that the TP will provide to indicate the potential for congestion/curtailment; this uncertainty is affecting wind development.
MTU	7.	a.	7	Unscheduled flows have caused Path 18 to exceed its OTC rating in the past. However, the path operator has limited ability to control flows. Knowing the cost of congestion would be helpful.
MTU	7.	a.	8	The cost of congestion has not been used for making investment decisions.
GEN	7.	a.	9	More price transparency would make siting decisions more rational.
MKTR	7.	a.	10	Congestion, whether real or administrative is difficult to consider in investment decisions.

				Problem Identification and Quantification Survey - preliminary results [draft_031105]
MTU	7.	a.	11	Because there is no congestion management system in place which places a value on congestion, schedules are cut or denied to maintain reliability operation and costs are internalized.
MTU	7.	a.	12	Transmission owners are expected to make economic transmission upgrade decisions; new users are expected to fund expensive transmission upgrades with little dispatch information.
MTU	7.	a.	13	Under today's market design the region does not have an independent, coordinated process to address expansion needed to cure chronic commercial congestion.
TDU	7.	a.	18	Difficult to finance based on an interruptible transmission contract even if physically hedged by local generation.
GEN	7.	a.	14	Respondent's LSE notes no such impacts to date.
TDU	7.	a.	15	We have no vested interest in system planning.
TDU	7.	a.	16	We have not experienced any problems in this area.
TDU	7.	a.	17	Aware of congestion and performs resource planning around known congestion points.
	7.	b.		Allocation of Costs and Benefits
GEN	7.	b.	1	The allocation of costs associated with an upgrade of McNary-John Day remains uncertain, e.g., argument results when trying to determine what portion of the the upgrade is for reliability and what portion is needed for expansion.
MKTR	7.	b.	2	A status review of BPA's G20 projects would be helpful; Puget Sound and Kangley-Echo Lake upgrades were delayed due to disagreement of allocation of costs.
MTU	7.	b.	3	The uncertainty about the cost and benefit allocation associated with the uncontrolled flows on Path 18 may cause a delay in this investment.
MTU	7.	b.	4	A potential generating facility and TP may disagree about the allocation of transmission improvements which could cause delay in upgrade investments as well as confusion in queue positions.
MTU	7.	b.	5	When expansion is ahead of contracted demand; the uncertainty over cost allocation and who benefits becomes critical.
TDU	7.	b.	6	There is an ongoing disagreement among entities in the Puget Sound area over the solution and cost allocation of maintaining adequate transmission capacity on the Northwest Intertie.
TP	7.	b.	7	The path capacity allocation process often results in a path capacity right that is limited by underlying facilities (Example provided involves 140 MW). In spite of lower impedance (higher voltage), paths carrying a higher percentage of the power, the existing, underlying paths are usually granted the capacity that existed before adding a new facility was added. This may create a disincentive to construct new facilities since they are unlikely to receive the full capacity of the facility.
GEN	7.	b.	8	Changes in the terms of interconnection and transmission costs after project commencement have been a problem.
MKTR	7.	b.	9	System benefits created by and paid by interconnecting entities are often ignored or not disclosed by transmission providers. Examples include switching capabilities, monitoring improvements, improved stability margins.
GEN	7.	b.	10	When dealing with BPA and another provider of service, disagreements, delays and inaction is the name of the game. We have to accept less than optimal solutions because of conflict over cost allocation.
MTU	7.	b.	11	The present system of transmission planning is done primarily on an individual control area basis, with only limited regional coordination. Examples of the much-acknowledged reasons for lagging transmission infrastructure investment include inconsistently adopted and applied development criteria, unclear cost recovery mechanisms, and unknown effects from parallel system operation.
TDU	7.	b.	16	Delays have been caused by inability of parties to agree on how transfers by other parties impacted service requested.
TDU	7.	b.	12	We have not experienced any problems in this area.
TDU	7.	b.	13	We are not part of any transmission project so have no experience in the described delays.
MTU	7.	b.	14	We use a "build for contract" planning model for transmission expansion so there is no uncertainty on the allocation of costs.
MTU	7.	b.	15	We have no examples of how uncertainty about cost/benefit allocation has impacted investment decisions, however, funding responsibilities typically fall on generation owners/purchasers.
	7.	c.		Suggestions for Planning Coordination Improvements
MTU	7.	c.	1	The addition of Northwest Transmission Assessment Commission has improved regional planning; the challenge of getting the plans built and paid for remains.
GEN	7.	c.	2	The existing planning efforts, e.g., NTAC, are driven by utility, individual generator and transmission owner interests and as a result, are expected to come up with biased answers.

				Problem Identification and Quantification Survey - preliminary results [draft_031105]
MKTR	7.	c.	3	There is a disconnect between planning and operations which is further complicated by a lack of coordination at the regional level. This disconnect is manifest in pre-schedule curtailments.
MKTR	7.	c.	4	January 2004 was a wake-up call for the Puget Sound Area; area utilities likened the problem to "looking over the abyss" and the industry-equivalent of the canary in the mine.
MKTR	7.	c.	5	NTAC holds promise, however, the planning is being done at a high level and nothing will happen without cost-allocation.
MTU	7.	c.	6	Planning efforts have been hindered by multiple requests in the queue and unclear FERC guidelines on how to deal with impacts on third parties. Regional queues could reduce confusion.
MTU	7.	c.	7	FERC has made the local transmission utility responsible for new generation interconnection; this has a significant regional impact; coordinated planning could help optimize the tx system.
MTU	7.	c.	8	If new requests are substantive, planning coordination is fundamental in determining the least-cost transmission path.
TDU	7.	c.	9	There needs to be a commitment of utilities to provide resources for the planning efforts that are currently underway; the formation of NTAC can address reliability issues and commercial needs.
TDU	7.	c.	10	We believe that some coordination between systems is going on now; efficiencies may be gained by having planning staff work more closely together, e.g., on non-wires solutions.
GEN	7.	c.	11	Regional planning in the context of an independent organization should improve processes for evaluating transmission needs.
MTU	7.	c.	12	For Transmission Owners, an "I'll do it myself" attitude leads to non-optimal solutions and delays (Examples provided).
TDU	7.	c.	13	In an age where BPA will face increasing constraints on its borrowing authority, it will be critical to have coordination of planning as well as allocation of costs of expansion; BPA won't be able to do it all anymore.
MTU	7.	c.	14	A new paradigm is needed where infrastructure planning is facilitated by the use of a flow-based methodology instead of the contract path methodology now used.
GEN	7.	c.	15	There is a big disconnect between planning and operations.
TDU	7.	c.	16	Has mandatory coordinated transmission planning function in existing contract.
	7.	d.		Services Currently Not Available or Open to Third Party Providers
MTU	7.	d.	1	A transmission product for wind generation is needed; something that is less firm than other transmission.
GEN	7.	d.	2	Redispatch markets and mature secondary markets could enable the construction of renewable resources; wind is typically a 30-35% capacity factor resource.
MKTR	7.	d.	3	A single regional queue would help merchants arrange for multiple transmission legs at once.
MTU	7.	d.	4	The problem isn't a planning issue; the G20 projects, if installed, would address most congestion. The problem is funding of upgrades.
MKTR	7.	d.	5	Order 888 tariffs were not designed with intermittent resources in mind; a pay-as-you-go product with monthly settlements is needed.
MTU	7.	d.	6	We are not aware of any desired service that is not available; there are opportunities to improve AS, e.g., Black Start, Interruptible Reserve (interruptible load), and limited-period firm service.
TP	7.	d.	7	Balancing energy and reserves markets would need beneficial.
GEN	7.	d.	8	Ability to provide and acquire ancillary services at market-based rates including: balancing energy, operating reserves, reactive power, load following and frequency response.
MKTR	7.	d.	9	Operating reserves, reactive power supply, balancing energy, load following and frequency response.
MTU	7.	d.	10	We need a single planning forum with responsibility and authority to ensure that planning is done in an open and coordinated manner and to identify least-cost solutions.
TDU	7.	d.	13	Moving to injection/withdrawal approach would result in more efficient use of transmission. Local generation that can solve short-term transmission constraints could be compensated for its value.
GEN	7.	d.	11	Respondent's LSE has generally been able to find or develop any services that are needed and cost-effective.
TDU	7.	d.	12	We find that the transmission services available today are adequate to meet our needs.
	7.	e.		Additional Information
MKTR	7.	e.	1	The cost of congestion, although not well tracked, results in foregone transmission (long-term and secondary services) and higher energy expenses. It also increases price volatility.
MTU	7.	e.	2	One approach to valuing congestion would be to measure the difference between energy prices during congested and non-congested time periods.

				Problem Identification and Quantification Survey - preliminary results [draft_031105]
MTU	7.	e.	3	There are too many planning activities underway; getting these organized could mean reducing or eliminating some activities.
MTU	7.	e.	4	Though today we have some ad hoc cooperation on certain projects, respondent believes that without an independent entity leading this effort the region will not be able to implement the most efficient transmission investments over time.
	7.	f.		Other Comments
GEN	7.	f.	1	Transmission services sold on a usage or volumetric basis ($/MWh) would benefit wind generation. This could be a change to rates that an RTO would adopt.
GEN	7.	f.	2	BPA and Pac have removed the imbalance penalty for wind which may be adopted broadly with the establishment of a regional RTO.
GEN	7.	f.	3	Studies regarding the cost of integrating wind power support the conclusion that the larger the control area, the lower the cost to integrate wind generation.
GEN	7.	f.	4	The problems associated with clearing the BPA long-term transmission queues (for both interconnection and service) might be better administered by a regional RTO.
MTU	7.	f.	5	The region needs an independent entity to monitor wholesale power markets as well as Grid Wests compliance with its own tariff.
MTU	7.	f.	6	The market monitor would also promote transparency of market data, monitor seams, and recommend ways to ensure compatibility between newly developing and existing markets.